Witness: Edward A. Davis
Request from: Division of Energy Resources

Question:
Please provide copies of the resulting Orders and Tariff Sheets from Docket Nos. 92-11-11 and 99-03-36.

Response:
Attached are the Orders and Tariff Sheets from these dockets pertaining to standby service.

DOCKET NO. 92-11-11

APPLICATION OF
THE CONNECTICUT LIGHT AND POWER COMPANY
TO AMEND ITS RATE SCHEDULES

DECISION

JUNE 16, 1993

Collaborative Group should be filed in Docket No. 93-04-01, DPUC 8th Annual Review of CL&P & UI Integrated Resource Planning/Status of Private Power Producers and Conservation and Load Management, so that it can be incorporated into that Decision.

12. Supplemental Service Rate 984 and Backup and Maintenance Power Service Rate 985

The COSS treats Rate 985 as a separate rate class and the Company proposes to make it mandatory for all partial requirements customers. The Company also modified language regarding the determination of backup demand. CIEC and the Connecticut Cogeneration Coalition ("CCC") disagree with certain aspects of Rate 985 and recommend modifications.

CIEC suggests that the AED-12CP/NCP method not be used to establish rate design and revenue requirements for standby customers taking service on Rate 985 for two reasons. The first is that the method does not properly account for the diversity of loads of standby customers. Second, Mr. Brubaker, the CIEC witness, claims that outages for cogenerators are random and therefore "the results that occur for any given 12-month period are not necessarily representative of what may occur in a different 12-month period." Id., p. 31.

The Authority will allow the Company to separate Rate 985 in its COSS as proposed. The Company applied the 12-CP/NCP method to Rate 985 as it does to other rate classes and used actual loads that were applied correctly. All classes are subject to variances in usage which might alter the results in any particular COSS; however, the use of the 12-CP/NCP method reduces this problem more than many cost allocation methods. Since the COSS uses class NCP, it does not acknowledge much benefit from shifting loads to off-peak, daily, weekly, or seasonal periods. This methodology has been accepted to date due to the NU's system, but the Authority recognizes that this method may result in a low rate of return for time of use and seasonal customers. As discussed in Section II.H.1., above, the Company will run several COSS for its next rate case in addition to the one approved in this case to provide guidance for revenue allocation.

CCC recommends that the Authority reject the Company's proposal that Rates 984 and 985 be mandated for partial requirements customers. The Department rejected a similar proposal by UI in Docket No. 89-08-11, Application of The United Illuminating Company for an Increase in Rates. Decision, 1/24/90, p. 63. The Authority believes that it would be discriminatory to require cogenerators to be on Rate 985 but not other customers with similar load characteristics. The Authority will therefore reject the Company's proposal to make Rates 984 and 985 mandatory for partial requirements customers.

The level of contract demand is an important factor in determining billing under Rate 985. The tariff contains a formula which determines the percentage of usage during peak hours to total peak hours. The percentage is then increased by an exponent of 6 then applied to the contract demand and multiplied by the regular applicable service rate P/T demand charge. The P/T charge determined by the equation is ratcheted because the percentage is based on the sum of back up loads taken on each on-peak hour of the latest six months of December, January, February, June, July, and August

CCC believes that the tariff language for Rate 985 requires a higher or lower contract demand than is needed by the customer. The Coalition recommends that the language be simplified to say: "To obtain service under this schedule, the customer must specify in writing the maximum demand (Back-up Contract Demand) which it plans to impose on the Company under this rate schedule, but not to exceed actual output of the customer's generation."

The Authority agrees. The proposed language is overly complicated and may have unintended outcomes. The Authority will order the Company to substitute the language above for its proposed language.

CIEC recommends that customers on Rate 985 be allowed to select backup contract demands that may vary by season. The Authority will not approve this proposal at this time. The Authority does not believe that it is appropriate to change the contract demand seasonally for the determination of the distribution demand charge. The current practice is consistent with all other demand rates which the charge is based on maximum demand and recalculated for eleven months. This is proper because a large part of distribution costs are customer related. The Authority is more open to seasonal adjustments for contract demand for determination of the P/T charge. These costs are not customer specific. There may be advantages to the Company if it knows that demands will be lower during particular periods. Unfortunately there is not enough evidence on the record about the pros and cons of this proposal and it practicality therefore, the Authority will not order any changes at this time.

CIEC proposes that exponent of 6 used in the equation to determine the P/T demand charge be reduced to 1 and then applied to the maximum on-peak standby demand rather than contract demand.

The use of contract demand coupled with a high exponent and the ratchet appears to come up with a high rate. On the other hand, a rate based on actual demand with an exponent of 1 as proposed by CIEC may be too low. Since Rate 985 already has a reservation charge for production and transmission demand in the form of a minimum charge of $1.00 per kW of back-up contract demand the Authority agrees with CIEC that the formula should determine the P/T demand charge based on actual demands. The Authority will order this revision to the rate. The modifications, which eliminate the mandatory requirement and the use of contract demand to determine demand charges, will benefit cogenerators. Given these modifications, the Authority will not change the exponent at this time. The Authority recognizes that the exponent is higher than that used by WMECO; however, rates are not the same between jurisdictions, nor do the Commissions always agree on the philosophy of rate design.

CL&P LIST AND APPLICABILITY OF RATES AND RIDERS

Rate 1 — **Residential Electric Service (Non-Heating)** Single family homes, apartments, and farms where residential uses are more than 50% of energy use. Includes Controlled Water Heating Block Pricing
- Rate 7 and Rider N
- Effective 7/1/93

Rate 5 — **Residential Electric Heating Service** Single family homes, apartments, and farms where residential uses are more than 50% of energy use. Includes Controlled Water Heating Block Pricing
- Rate 7, Rider N and CSR
- Effective 7/1/93

Rate 7 — **Residential Time-Of-Day Service** Optional Rate for Residential
- Rider N
- Effective 7/1/93

Rate 18 — **Controlled Water Heating Electric Service** Optional Rate used for water heating only, no space or C&I process heating. Small General Service Rates with restricted applicability for Residential.
- Effective 7/1/93

Rate 19 — **Intermediate Interruptible Service Menu** Optional Rate for Customers with at least 300 kW of radio controlled, mandatory interruptible load.
- LTED
- Effective 7/1/93

Rate 20 — **Customer Controlled Interruptible Service Menu** Optional Rate for Customers with at least 300 kW of manual control, mandatory interruptible load.
- LTED
- Effective 7/1/93

Rate 21 — **Intermediate Interruptible Service** Optional Rate for Customers with at least 300 kW of interruptible load. Energy charges are based on weekly forecast of Marginal Energy Cost.
- LTED
- Effective 7/1/93

Rate 27 — **Small Time-Of-Day General Electric Service** Optional Rate for Small General Service Customers
- Rider N, 5 Yr ED, and TDR
- Effective 7/1/93

Rate 29 — **Outdoor Recreational Lighting Service** Optional for Lighting Only between 7 PM and 7 AM.
- None
- Effective 7/1/93

Effective Date 7/1/1993

CL&P LIST AND APPLICABILITY OF RATES AND RIDERS

Rate 30 — **Small General Electric Service** General Service for Customers with Annual Maximum Demands less than 350 kW.
- Rates 18, 27 and 35, and Riders N, 5 Yr ED, and TDR
- Effective 7/1/93

Rate 35 — **Intermediate General Electric Service** General Service for Customers with Annual Maximum Demands less than 350 kW. Energy charges are based on weekly forecast of Marginal Energy Cost.
- Rates 18, 27 and 30, and Riders A, Rider N, 5 Yr ED, TDR, CG&BR, BR, and, in rare cases, VCR
- Effective 7/1/93

Rate 39 — **Interruptible Service Menu** Customers with at least 2000 kW interruptible load.
- LTED, TDR
- Effective 7/1/93

Rate 40 — **Small Church and School Electric Service** open only to existing customers on Rates 40 and 41 with Annual Maximum Demands less than 350 kW, Non-Profit Schools only.
- Rates 18, 27, 30 and 35 and Riders N, TDR, and CG&BR.
- Effective 7/1/93

Rate 41 — **Large Church and School Electric Service** Mandatory Time-Of-Day for Customers with Annual Maximum Demands greater than or equal to 350 kW, Non-Profit Schools only, open only to existing customers on Rates 40 and 41.
- Rates 19, 20, 21, and 56 and Riders TDR, DRR, VCR, and CG&BR.
- Effective 7/1/93

Rate 55 — **Intermediate Time-Of-Day Electric Service Manufacturers** Mandatory for Customers with Annual Maximum Demands greater than or equal to 350 kW but less than 1000 kW, unless the Customer opts for an Interruptible Rate. Sales Tax Exempt Industrial Customers only.
- rates 19, 20, 21, and Riders 5 Yr ED, BR, CG&BR, TDR, DRR, VCR, LTED and EOPD.
- Effective 7/1/93

Rate 56 — **Intermediate Time-Of-Day Electric Service Non-Manufacturers** Mandatory for Customers with Annual Maximum Demands greater than or equal to 350 kW but less than 1000 kW, unless the Customer opts for an Interruptible Rate. Non-Sales Tax Exempt C&I Customers and large governmental, educational, and religious institutions.
- 5 Yr ED, BR, CG&BR, TDR, DRR, VCR, LTED and EOPD.
- Effective 7/1/93

Effective Date 7/1/1993

CL&P LIST AND APPLICABILITY OF RATES AND RIDERS

Rate 57 — **Large Time-Of-Day Electric Service Manufacturers** Mandatory for Customers with Annual Maximum Demands greater than or equal to 1000 kW, unless the Customer opts for an Interruptible Rate. Sales Tax Exempt Industrial Customers only.
- Rates 19, 20, 21, and 39 and Riders 5 Yr ED, BR, CG&BR, TDR, DRR, VCR, LTEP and EOPD.
- Effective 7/1/93

Rate 58 — **Large Time-Of-Day Electric Service Non-Manufacturers** Mandatory for Customers with Annual Maximum Demands greater than or equal to 1000 kW, unless the Customer opts for an Interruptible Rate. Non-Sales Tax Exempt C&I Customers and large governmental, educational, and religious institutions.
- Rates 19, 20, 21, and 39 and Riders 5 Yr ED, BR, CG&BR, TDR, DRR, VCR, LTED and EOPD.
- Effective 7/1/93

Rate 115 — **Unmetered Electric Service** Special Purpose and Lighting Applications with Fixed Schedule of Constant Usage, Customer Owned Equipment.
- Effective 7/1/93

Rate 116 — **Street and Security Lighting** Road and Parking Lighting using Company Owned Equipment and Poles, Unmetered.
- Effective 7/1/93

Rate 117 — **Partial Street Lighting Service** Road and Parking Lighting using Customer Owned Equipment and Poles, Unmetered.
- Effective 7/1/93

Attachment 3 — **Monthly Street Lighting Rates for Partial Service** Closed Rate, A Mix of Company and Customer Ownership of Equipment and Energy.
- Effective 8/20/91

Rate 980 — **Non-firm Power Purchase** Customers that self-generate with excess energy to sell to the Company, No other contract for sale of power.
- Effective 4/1/93

Rate 984 — **Supplemental Power Service** Customers that self-generate but need additional energy regularly to operate.
- Rate 985 and General Service Rates are available for this service.
- Effective 7/1/93

Rate 985 — **Back-Up and Maintenance Power Service** Customers that self-generate with a need for service during periods when the Customer's generation is unavailable.
- General Service Rates are available for this service.
- Effective 7/1/93

Effective Date 7/1/1993

CL&P LIST AND APPLICABILITY OF RATES AND RIDERS

Rider N — **Self-Generator Net Energy Billing Service** Customers with small generating capacity - up to 50 kW or to 100 kW, if renewable fuel - can net their generation from their usage.
- Rates 1, 5, 7, 27, 30, 35, and 40.
- Effective 6/19/86

CSR — **Construction Standard Rider** Minimum building standards for a house to be allowed the use of electricity as the primary space heating source.
- Rate 5
- Effective 7/1/93

Rider A — **Optional Off-Peak Service** Limits the measurement of Production and Transmission Demand and the determinant of the energy first block to maximum monthly on-peak demand.
- Rate 35
- Effective 8/20/91

DRR — **Demand Reduction Rider** Customers who have maximum annual on-peak demands greater than or equal to 350 kW and can interrupt at least 300 kW of load in at least four months of the year within one or four hours of notice. Monthly credits or penalties based on performance.
- Rates 41, 55, 56, 57, and 58.
- Effective 7/1/93

VCR — **Voluntary Curtailment Rider** Customers who have at least 250 kW of interruptible load and can do so at the request of the Company. Provides credit only for actual interruption provided per request.
- Rates 35, 55, 56, 57, or 58.
- Effective 7/1/93

TDR — **Transitory Demand Rider** Waives any bill consequences beyond the month of occurrence of a previously approved spike in a Customer's one month's demand above currently prevailing maximum demand.
- All Rates with demand or kW based facilities charges.
- Effective 8/20/91

BR — **Business Recovery Rider** Provides discounts on a Customer's bill for Customers who are experiencing short-term, reversible financial duress and have a plan for recovery.
- Rates 35, 55, 56, 57, and 58.
- Effective 7/1/93

Effective Date 7/1/1993

CL&P LIST AND APPLICABILITY OF RATES AND RIDERS

CG&BRET	**Competitive Generation and Business Retention Rider** Provides discounts on a Customer's bill for Customers who have viable relocation or self-generation options to full requirements service in CL&P service area. – Rates 35, 40, 41, 55, 56, 57, and 58. – Effective 7/1/93
5 Yr ED	**Economic Development Rider** New or Existing Customers that have an option to move into or expand operations in CL&P's service area with an increase of load of 50 kW or more, and that depends on aid and discounts from the State and/or the Company. Maximum duration 5 years. – Rates 27, 30, 35, 55, 56, 57, and 58. – Effective 7/1/93
LTED (10 years)	**Long-Term Economic Development Rider** New or Existing Customers that have an option to move into or expand operations in CL&P's service area with an increase of load of 350 kW or more, and that depends on aid and discounts from the State and/or the Company. Maximum duration 10 years. – Customers are on or shall be served on Rates 19, 20, 21, 39, 55, 56, 57 or 58. – Effective 7/1/93
EOPD	**Experimental On-Peak Demand Rider** Available only to Rates 55, 56, 57 or 58 customers, both existing and new, for incremental load of at least 500 kW that has not been served by the Company. Not available to any customers receiving a discount on the Economic Development, Long-Term Economic Development, Business Recovery, or the CG&BRET. – Effective 7/1/93

THE CONNECTICUT LIGHT AND POWER COMPANY

BACK-UP AND MAINTENANCE POWER SERVICE RATE 985

APPLICABILITY: This rate is available to all partial requirements general service customers (the customer) who require back-up and maintenance service. All electricity shall be measured through one meter, except that where the Company deems it impractical to deliver electricity through one service, or where the Company has installed more than one meter, then the measurement of electricity may be by two or more meters. All electricity supplied shall be for the exclusive use of the customer and shall not be resold. Service taken under this rate shall be electrically separated from the customer's generating facilities or provided with sufficient protective devices to prohibit such facilities from causing disturbances on the Company's system. The Company reserves the right to refuse service to facilities where the Company deems the protection provided to be inadequate.

Back-Up Power is intended to provide the customer with a back-up supply of power when the customer's generating facilities are not in operation or are operating at less than full rated capability. To obtain service under this schedule, the customer must specify in writing the maximum demand (Back-Up Contract Demand) which it plans to impose on the Company under this schedule, but not to exceed actual output of the customer's generation.

Demands imposed on the Company by the customer in excess of the customer's Supplemental Contract Demand, under Rate 984, if any, shall be deemed to be Back-Up Power and billed accordingly up to the previously specified Back-Up Contract Demand. When the customer imposed demand exceeds the specified Rate 984 Supplemental Contract Demand plus the Back-Up Contract Demand, the customer imposed demand minus the previously specified Back-Up Contract Demand shall become the customer's new Supplemental Contract Demand.

The customer shall furnish, at the customer's expense, necessary facilities whereby the Company can meter the output of the customer's generating facilities.

MONTHLY RATE: The customer shall be billed for service, in accordance with the applicable general service tariff available to the customer for the size of service taken based on the Back-Up Contract Demand Level except as modified below.

Production/Transmission Demand or Contribution Charge:

Customers shall pay the greater of:

A. D times $(1-(1-K/2080)^6)$ per kW of Production/Transmission in demand,

where D equals the applicable general service rate's Production/Transmission Demand Charge, or, if absent, then the general service rate's total demand charge less \$4.00 after July 1, 1993, and \$4.50 after July 1, 1994.

Where K equals the sum of the backup/standby loads taken in each on-peak hour of the latest six months of December, January, February, June, July, and August divided by the contracted backup/standby demand, or

B. the Production/Transmission Demand Charge of \$1.00 per kW of Back-Up Contract Demand.

The minimum monthly charge shall be the sum of a) the Customer Service Charge plus b) the product of the Distribution Demand or Facilities Charge and the Back-Up Contract Demand plus c) the Production/Transmission Demand or Contribution Charge determined above.

Where service is taken under this schedule the demand shall be the actual maximum demand less the applicable Supplemental Contract Demand. Billing energy shall be kWh consumed at levels in excess of the Supplemental Contract Demand.

MONTHLY ENERGY ADJUSTMENTS: This rate shall, in accordance with procedures approved by the Public Utility Control Authority, be subject to increases or decreases reflecting changes in the costs of nuclear generation, conservation and fuel set forth in calculations submitted to the Authority for approval.

TERM OF CONTRACT: The minimum term of service under this, or any superseding rate schedule, is two years.

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 99-03-36 DPUC DETERMINATION OF THE CONNECTICUT LIGHT AND POWER COMPANY'S STANDARD OFFER

October 1, 1999

By the following Commissioners:

Donald W. Downes
John W. Betkoski, III
Jack R. Goldberg

DECISION

Table Of Contents

DECISION

I. INTRODUCTION

A. SUMMARY

Public Act 98-28, An Act Concerning Electric Restructuring, creates a competitive generation segment of the electricity industry, effective January 1, 2000. Customers will be able to buy generation services from licensed electric suppliers rather than from their former electric company. However, Section 20 of Public Act 98-28 requires that the former electric companies, now called electric distribution companies, make a full-service electricity offering available to all customers in their service area beginning January 1, 2000. The Act refers to this as standard offer service and it is available to all customers who affirmatively choose to receive electric generation services through their distribution company, or who do not, or are unable to, arrange for or maintain electric generation services with a licensed electric supplier. It is not available to customers who are presently receiving service under a special contract or interruptible rate. The standard offer is available from January 1, 2000 through December 31, 2003. Beyond that period, there are no more legally prescribed rate levels for fully bundled electricity service, and the market will determine the price of generation services, unless the standard offer is extended by the General Assembly. The price for the four-year standard offer is 10% below the fully bundled price for electricity at year-end 1996 and applies to each rate class. The Department is required to render a Decision on the standard offer by October 1, 1999.

In this Decision, the Department sets the parameters for each of the seven components of the standard offer. Those components include the charges for distribution, transmission, conservation, renewable energy and systems benefits. From those components, the Department will set the residual levels of the Competitive Transition Assessment and Generation Services Charge to achieve the required overall price reduction when combined with all components and by taking into account two important public policy considerations. The CTA is being set by the Department at a level to allow a reasonable time period for the CTA recovery and the GSC is set at a fair and competitively derived level to stimulate the newly competitive generation market. The final CTA and GSC will be determined following review of a filing pursuant to Order No 1 in this Decision. That Order requires the Company to recalculate the CTA consistent with this Decision and to provide the results of the competitive solicitation to supply generation services.

Most of the components of the standard offer were cost based and previously included in the total regulated rate set when the Company was a fully integrated utility. However, they were never unbundled. The salient features of the rate components set in this Decision are as follows:

- Distribution rates have been set by unbundling the revenue requirements for this function as set from the last rate case and as functionalized on a cost-of-service methodology;

- Transmission rates are consistent with tariffs set by the Federal Energy Regulatory Commission. The Department will allocate between transmission/distribution plant in accordance with FERC guidelines and subject to FERC approval.

- Conservation and renewable energy investment charges are new and set by Public Act 98-28: three mils per kilowatt hour of electricity sold for conservation and load management programs and one-half of one mil per kilowatt hours in 2000 to promote renewable energy sources, and increasing by one-quarter of a mil on or after July 1, 2002, and again on or after July 1, 2004;

- Systems Benefits Charge components were set in a Department Decision issued February 5, 1999. The Decision in the instant docket determines the charge and manner of recovery such that the exemption from the charge by special contract customers does not result in an increase in rates to any other customer;

- Competitive Transition Assessment recovers the Company's previously identified and quantified stranded costs, mitigation expenses and offsets. The components include amounts sufficient to recover all costs related to rate reduction bonds; interim nuclear capital costs and stranded costs. Important in this charge is the Department's determination of the amount that represents the Company's return of and on past nuclear investments only up to June 30, 1997, while recognizing on-going nuclear O&M expenses commensurate with prudent and efficient operation. Similarly, the revenues realized from the sale of the output of nuclear facilities is indexed to prudent and efficient operational characteristics and the revenues from those sales will be credited against stranded costs as mitigation. However, the Department rejects the Company's proposed nuclear sharing mechanism whereby annual nuclear revenues would be compared to annual plant-specific expenses and ratepayers would either be charged or credited for differences.

- Generation Services Charge is the cost of electricity for customers that do not choose a competitive licensed electric supplier. This energy supply will be the actual cost to CL&P to procure this service and will be based on a competitive solicitation, with some adjustments made by the Department to better reflect actual competitive offerings for this service by licensed electric suppliers. CL&P will procure one-half of the supply through the solicitation and the other half from a Company affiliate, Select Energy. The results of the solicitation have not been finalized and the actual cost is unknown at this time.

The system average standard offer rate is set at 9.34 cents per kWh. This level ensures that total rates charged under the standard offer are 10 percent less that rates in effect on December 31, 1996.

B. Background

By application dated April 30, 1999 (Application), filed pursuant to Public Act 98-28, An Act Concerning Electric Restructuring (Act), The Connecticut Light and Power Company (CL&P or Company) requests the Department of Public Utility Control's (Department) approval of its standard offer service and related rate components

(Standard Offer). The Company also requested that the Department issue an Interim Decision on CL&P's standard offer supply arrangement proposal.

On May 21, 1999, the Department issued a Filing and Procedural Order and Data Request (May 21 Order) that required the Company to revise its filing to delete certain proposals that the Department found were inconsistent with the Act. The Department also ordered the Company to provide additional information regarding amortization schedules. Further, the Department granted the Company's request for an Interim Decision on its proposed supply plan.

On June 9, 1999, the Company filed a revised application (June 9 Revision) in accordance with the May 21 Order. On July 26, 1999, the Company filed a second revision (July 26 Revision), which the Company stated was to comply with Orders in the July 7, 1999 Decision in Docket No. 99-02-05, Application of The Connecticut Light and Power Company for Calculation of Stranded Costs (Stranded Cost Decision).

C. CONDUCT OF THE PROCEEDING

By Interim Decision dated July 9, 1999, the Department approved the Company's proposed supply plan with certain modifications.

Pursuant to a Notice of Hearing dated July 1, 1999, the Department held a public hearing in this matter in its offices, Ten Franklin Square, New Britain, CT 06051, on August 5, 6, 9, 19, 17, and 18, 1999. At the August 18, 1999 hearing, the presiding Commissioner kept the record open to receive supplements to certain Late Filed Exhibits. The hearing was closed by Notice of Close of Hearing dated August 27, 1999.

By Notice of Request for Briefing of Issue dated August 19, 1999, the Department requested that parties and intervenors in this proceeding include in their briefs a discussion as to whether the Federal Energy Regulatory Commission's (FERC) Order 888 (Order 888) automatically brings transmission under FERC jurisdiction once energy is unbundled.

The Department issued a draft Decision in this matter on September 21, 1999. All parties and intervenors were provided an opportunity to file written exceptions to and give oral argument on the draft Decision.

D. PARTIES AND INTERVENORS

The Department designated The Connecticut Light and Power Company, P.O. Box 270, Hartford, CT 06141-0270; the Office of Consumer Counsel (OCC), Ten Franklin Square, New Britain, CT 06051; and the Utilities Operations and Management Analysis Unit of the Department (UOMA), Ten Franklin Square, New Britain, CT 06051 as parties to this proceeding. Amtrak, Connecticut Industrial Energy Consumers (CIEC), and Enron Energy Services (Enron) requested and were denied party status, but were granted intervenor status.

AllEnergy, Connecticut Cogeneration Coalition (CCC), Connecticut Conference of Municipalities (CCM), Connecticut Small Power Producers Association (CSPPA), Green Mountain Energy (Green Mountain), H.Q. Energy Services (US) Inc. (H.Q.), Office of the Attorney General of the State of Connecticut (AG), Town of Waterford (Waterford), and Utility.Com requested and were granted intervenor status.

II. DEPARTMENT ANALYSIS

A. STANDARD OFFER RATE DETERMINATION

The Standard Offer rate is a cumulative one comprising seven unbundled functions: (1) the distribution rate, (2) the transmission rate, (3) the Generation Services Charge (GSC), (4) the System Benefits Charge (SBC), (5) the Conservation and Load Management Charge (C&LM), (6) the Renewable Energy Investment Charge (Renewables Charge), and (7) the Competitive Transition Assessment (CTA). The Act requires that the Standard Offer rate be 10% less than rates in effect on December 31, 1996 (Rate Cap).[1] Rate unbundling and the Rate Cap are key to the implementation of the Standard Offer rate, and were the source of much of the contention among the parties in this proceeding.

The unbundled components of the Standard Offer rate have distinct cost characteristics. The distribution and SBC components are determined in accordance with the traditional, regulatory cost-of-service model. The FERC-approved tariffs govern the transmission rate. The C&LM and Renewables Charge are mandated, per kilowatt hour (kWh) charges. The GSC is determined by the Department during the standard offer period. The CTA may function as the residual cost component, but at all times it must, among other things, recover sufficient revenue to pay the principal of and the interest on rate reduction bonds and pay down stranded costs. See Section 10(d) of the Act.

The Rate Cap creates a zero-sum situation because it places a ceiling on the aggregated, Standard Offer rate. Below this ceiling, certain disaggregated, or unbundled, components may be adjusted.[2] As one component is raised, another must be lowered. The table below provides an illustration of this fact.

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[1] Subject to adjustment pursuant to Section 20(a) of the Act.

[2] The C&LM and the Renewables Charge are not subject to adjustment: they are per kWh charges mandated by the Act. See Section 33(a) and Section 44(b) of the Act, respectively.

Standard Offer Rate Proposals

	30-Apr-99	9-Jun-99	26-Jul-99	10-Aug-99
Distribution Rate	2.75	2.67	2.76	2.73
Transmission	0.38	0.38	0.38	0.38
GSC	3.35	3.43	3.81	3.84
SBC	0.31	0.31	0.31	0.31
C&LM	0.3	0.3	0.3	0.3
Renewables	0.05	0.05	0.05	0.05
CTA	2.2	2.2	1.73	1.73
Total Standard Offer Rate	9.34	9.34	9.34	9.34

Sources: Application, p. 25; July 26 Revision, p. 3;
Late Filed Exhibit No. 33-RV01.

Note: all charges except C&LM and Renewables are system averages.

Of particular import in this proceeding are proposed rates and rate adjustments to the distribution charge, the GSC and the CTA. The institution of these unbundled rates is consequential to the initial development of the competitive marketplace for electric generation services.

1. Ten Percent Rate Reduction

The Act requires that individual rate schedules be reduced by 10%. To fulfill the Act's mandate, the Company must assure that the Standard Offer rate be at least 10% less than the base rates in effect on December 31, 1996.[3] All customers must receive this discount, with the exclusion of those customers who, on or after July 1, 1998, are purchasing electric services under a special contract or flexible rate tariff. See Section 20(a)(2)(3) of the Act.

As a result of Decisions issued by the Department since December 31, 1996, the Company's current rates are less than the total amount charged to end use customers on December 31, 1996.[4]

In the Rate Case Decision, the Department reduced the Company's revenue requirements by 9.68 percent. Decision, p. 185. Four percent of this reduction was applied as a line item credit to base rates in each rate schedule, with the exception of interruptible rates, special contracts and flexible rate riders. Id. The discontinuation of the Fuel Adjustment Clause (FAC) and Generation Utilization Adjustment Clause (GUAC), in conjunction with a current Energy Adjustment Clause (EAC) rate of zero, further lowers rates, by about one percent, from the level in effect on December 31,

[3] According to Section 3(a) of the Act, "'[B]ase rates' means the total amount charged by an electric company to each end use customer class, as defined in its rate order in effect on July 1, 1998, for the fully bundled costs of electricity, including any customer service charge and any demand charge."

[4] See the Decision dated February 5, 1999, in Docket No. 98-01-02, DPUC Review of The Connecticut Light and Power Company's Rates and Charges – Phase II; and the Decision dated October 8, 1996, in Docket No. 95-07-05, DPUC Investigation of a Fully Tracking Energy Adjustment Clause for Electric Companies.

1996. June 9 Revision, p. 7. Effectively, the Company is obligated by the Act to reduce its base rates by at least five percent from the levels in place on December 31, 1996.

To achieve the mandated 10% rate reduction from base rates in effect on December 31, 1996, CL&P must (1) arrive at appropriate pre-discounted rates; and (2) apply the 10% reduction to each rate schedule's pre-discounted rate, excluding customers receiving electric services under special contract or flexible rate tariffs.[5]

The Company proposes to add base rates to fuel adjustment clause rates in effect on December 31, 1996, to establish pre-discounted rates. It proposes to use base rates established in the Decision dated June 16, 1993, in Docket No. 92-11-11, Application of The Connecticut Light and Power Company to Amend Its Rate Schedules.[6] In addition, the Company will include charges and credits in effect on December 31, 1996, under its Generation Utilization Adjustment Clause (GUAC) and Fuel Adjustment Clause (FAC). June 9 Revision, p. 7. On December 31, 1996, the Company's GUAC charge was levied at .114 cents on a per kWh basis and its FAC charge was zero. Id. The Company unbundled the base rate prices in effect on December 31, 1996, and added the .114 cent per kWh GUAC charge to every energy charge within each rate schedule eligible to receive the 10% rate reduction, except street lighting Rates 116 and 117.[7] See Exhibit 10.

For Rates 116 and 117, the Company added the .114 cent per kWh GUAC charge to monthly rates effective on December 31, 1996, for each sub-category of lumen rating within each category of fixture. In addition, the pre-discounted rate was calculated in this method for various pole charges and adders. See June 9 Revision, Exhibit 11, p. 17 of 23. The Company's system average, pre-discounted Standard Offer rate is 10.32 cents per kWh. June 9 Revision, p. 24.

To apply the 10% reduction, the Company established target rates for each unbundled price component. The target rates are 10% less than pre-discounted rates. See June 9 Revision, Exhibit 8. Subsequently, the Company unbundled on a functional basis (functional unbundling) the energy and demand price components within the aggregated, target rate limit. Id. For each unbundled energy price, the Company unbundled first those functions that have required pricing: Renewables Charge, C&LM Charge, GSC, and SBC. June 9 Revision, p. 50. Residual energy prices are further reduced by transmission (to the extent that a rate schedule does not have a demand component) and the CTA: distribution is the residual rate design component. June 9 Revision, p. 51. Unbundled demand prices are reduced in the same order, with the exclusion of the Renewables Charge and C&LM, since these charges are mandated

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[5] For the purposes of this Decision, the term pre-discounted rates is synonymous with, and shall be used instead of, the term "base rates," as it is defined in the Act (see above.) The Department shall use the term base rates to mean those total rates (inclusive of customer, demand and energy charges) in each rate schedule of the Company's published tariff, established in a § 16-19 proceeding.

[6] As amended by the Settlement Agreement approved in the Decision dated July 1, 1996, in Docket No. 92-11-11.

[7] Base rate prices include the customer charge, energy charge(s) and demand charge(s). Note: an individual rate schedule may have multiple, or blocked, energy or demand charges (e.g., Rate 1 has three distinct energy charges: first 400 kWh, next 500 kWh, and all over 900 kWh.)

energy charges. Only the distribution component is reflected in the unbundled customer charge. See Exhibit 8.

According to the Company, certain rates, specifically, Rates 116, 117, 21, 39 and Flex Contracts, cannot be reasonably or practically unbundled on a functional basis and therefore will not be billed on an unbundled basis. June 9 Revision, p. 52; Tr. 8/18/99, pp. 1762-1763. For these rates, the Company assumed that unbundled functional components exist to illustrate implied, unbundled rates and to impute revenues on a functional basis. See June 9 Revision, p. 52; Exhibits 11 and 12. The Company's system average, discounted Standard Offer rate is 9.34 cents per kWh. June 9 Revision, p. 24. This average is 9.5% less than the system average, pre-discounted Standard Offer rate because certain rates did not receive the discount. Id.

The Company believes that the intent of the Act is to maintain the 10% overall rate reduction throughout the Standard Offer period. Response to Interrogatory OCC-60. However, it notes that certain adjustments to the overall rate are permissible under Section 20 of the Act. Id. The Company also asserts that the EAC and transmission rates, both individual components of the Standard Offer rate, are not subject to the Rate Cap. Response to Interrogatory OCC-60; Tr. 8/9/99, pp. 1083-1084.

The Company proposes to use the CTA as the residual revenue component. June 9 Revision, pp. 21-22, 57. Rate reductions necessitate revenue reductions. It is the Company's position that revenue reductions should not be applied to the unbundled distribution function for three reasons. First, the Company notes that the Act requires that "the total rate" charged under the Standard Offer shall be at least 10% less than rates in effect on December 31, 1996. Tr. 8/9/99, pp. 1127-1128. Second, CL&P argues that it would not be feasible to separate by function the production, transmission and distribution costs approved in the Decision dated June 13, 1993, in Docket No. 92-11-11. Id. Last, the Company claims that such a reduction in its distribution revenue requirement would be unsupported on a cost basis. Tr. 8/10/99, pp. 1370-1371.

The generation function encompasses two standard offer components: the GSC and the CTA. Simply put, the GSC covers electric generation services on a going-forward basis: the CTA, on the other hand, produces revenue necessary to recover past generation investments that cannot be recovered in a competitive generation market, that is, stranded costs. According to CL&P, the GSC will be established through competitive bids and should not be reduced. The Company proposes to reduce accelerated amortizations to regulatory assets ordered in the Stranded Cost Decision to obtain the 10% reduction. Consequently, the CTA will be allocated the entire mandated 10% reduction in revenue requirements. Tr. 8/6/99, p. 617.

Participants either approved of, or did not fault the Company's implementation of the mandated 10% rate reduction to individual rate schedules. AG witness Kahal agreed with the Company that the 10% rate reduction applies throughout the Standard Offer period. Contention among the parties arises primarily out of the Company's proposal not to apply the 10% reduction to the unbundled distribution function's revenue requirement.

Kahal takes issue with the Company's failure to allocate its pro rata share of rate reductions to the distribution function. Kahal PFT, p. 12. He notes that this failure lessens the amount of revenue available under the Rate Cap to pay down stranded costs and has the effect of (a) increasing stranded costs in absolute terms, and (b) increasing the stranded cost burden on customers after the Rate Cap is lifted in 2003. Tr. 8/6/99, pp. 617-618. With regard to the 10% rate reduction, Kahal believes that the Act's intent is to reduce unbundled rates in real terms, rather than achieve the rate reduction by deferring stranded cost recovery (through the CTA) until after the Rate Cap is lifted. Id., pp. 587-588.

The Department deems the Company's approach for implementing the 10% rate reduction to be permissible under the Act and therefore approves it as filed. Specifically, the Department finds that each step taken by the Company to reach the rate reduction objective is appropriate: (1) arrival at pre-discounted rates, (2) application of the rate reduction to individual rate schedules. Moreover, the Company's method yields a 10% rate reduction for each eligible rate schedule. See June 9 Revision Exhibits 9, 10 and 11.

The Company proposes to reduce the total amount charged to end use customers as of December 31, 1996, in accordance with the Act. Furthermore, it has reduced the total revenue requirement by over 10% from its total revenues in 1996. The table below compares revenue and revenue requirements for CL&P.

CL&P Revenue

Year	1996 (1)	1999 (2)	2000 (3)
Total Revenue $	2,397,459,783	2,299,569,000	2,095,021,000

(1) Total revenue: FERC Form 1, p. 114. Line 2.

(2) Total revenue requirement: Response to Interrogatory OCC-176.

(3) Total target revenue: July 26 Revision, Exhibit 1.

In the Rate Case Decision, which was rendered after the 1996 mandate, the Department increased amortizations. It would be fair to allow the Company to reverse those amortizations. CL&P's proposal to reduce amortizations to produce the 10% overall reduction to rates is therefore appropriate.

The Company's allocation of the 10% revenue reduction among unbundled functions is appropriate. Despite the fact that the Company's proposal does not allocate any of the reduction to distribution, it conforms to the letter of the Act. Absent explicit language in the Act directing the Department to implement a rate reduction for each unbundled rate of the Standard Offer, the Department is unwilling to reduce the Company's revenue requirement from cost levels deemed prudent in the Rate Case Decision and reflected in the As-Allowed COSS. Furthermore, the Department finds that the Rate Cap is effective throughout the Standard Offer period, subject to adjustments pursuant to Section 20 of the Act.

The Department rules that adjustments made to the transmission rate are subject to the Rate Cap. The transmission rate will be treated like the distribution rate. If either rate is adjusted in the course of a § 16-19 proceeding, during the Standard Offer period, it will be subject to the Rate Cap.

Furthermore, the Department rules that the Rate Cap will not apply to adjustments made pursuant to the EAC. Section 20(2) of the Act states that the standard offer shall be adjusted pursuant to General Statutes of Connecticut (Conn. Gen. Stat.) § 16-19b, which governs the EAC.

2. Special Contracts

Pursuant to Section 20 of the Act, customers who, on or after July 1, 1998, are receiving electric services under a special contract or flexible rate tariff shall not receive the mandated 10% rate reduction. In the SBC Decision, the Department determined that special contract customers are those that are either receiving electric service at a rate that is less than the customer's otherwise applicable tariff rate, or receiving service under a marginal cost based interruptible rate. Decision, p. 17. Additionally, the Department defined flexible rate tariff customers as those receiving electric service at a rate that is less than the customer's otherwise applicable firm service tariff but whose rate is based on a published tariff. Id.

According to CL&P, the Company will honor its special contracts in accordance with the statutory requirements of the Act, the Rate Case Decision, and the negotiated provisions of any individual agreement. June 9 Revision, p. 51. The Company proposes to modify the discounted general service rates to reflect those in effect on December 31, 1996, to assure compliance with the Act. Id., pp. 51-52. If it has been determined that customers would be better off on a post-restructured general service rate, they will be given the option to cancel the contract and move to the more favorable rate without any penalties (as may be provided under such customer's contract.) Non-generic agreements will be reviewed on a case by case basis to determine an equitable treatment for both parties.[8] Id., p. 52.

Most existing contracts are priced by reference to general service rates. Id., p. 51. Without modification, once the general service rates are reduced by 10%, these contracts would also be reduced, in direct violation of the Act. Consequently, the Company proposed to modify the discounted general service rate prices for Rates 21, 39, 119 and Flex Contracts so that they do not receive the 10% rate reduction.[9] See June 9 Revision, Exhibits 10 and 11, pp. 21-23.[10]

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[8] Non-generic special contracts have particular terms and conditions that complicate economic comparisons among rates. Tr. 8/9/99, p. 1137. Non-generic special contracts represent approximately 748,000 MWh annual average sales to CL&P. Response to Interrogatory EL-55.

[9] In 1998, approximately 2 million annual MWh sales were made under Rates 21, 39, 119 and Flexible contracts. See the Response to Interrogatory EL-78.

[10] Flex Contracts include: Economic Development, Business Recovery, Business Retention, Competitive Generation and Special Contracts. See Exhibit 11, pp. 23.

The Company's proposal to permit customers to leave their contract rates and move to a more favorable general service rate is appropriate. However, the Company's proposal leaves open the possibility that contract customers who wish to cancel their contracts and move to a competitive electric supplier's rate would be assessed a penalty (as may be provided under such customer's contract.) Contract customers, including special contract customers and flexible rate tariff customers, should not be penalized for leaving their contracts and moving to more favorable rates with competitive electric suppliers. Consequently, the Department orders the Company to permit all customers to cancel and move to the more favorable rates, whether they be general service (Standard Offer) rates or competitive supplier rates, without the imposition of any penalties.

3. Rate Stipulation

In response to a ruling from the bench by the presiding Commissioner that no rate changes other than those provided in the Act would be considered in this proceeding, CL&P, CIEC, The Taylor & Fenn Company, the Connecticut Cogeneration Coalition and the Connecticut Small Power Producers Association filed a stipulation (Stipulation) for Department approval. See Tr. 8/5/99, pp. 397-398. This stipulation, dated August 9, 1999, outlines an agreement regarding Rates 21, 39, 985 and the Demand Reduction Rider (DRR) The Stipulation states that CL&P shall defer its proposal to eliminate Rates 21, 39, 985 and the DRR until the next proceeding held pursuant to Conn. Gen. Stat. § 16-19. Additionally, it states that charges under Rates 21, 39, 985 and DRR shall remain at December 31, 1999, levels. As a consequence, the following will occur: (1) customers receiving services under these rates will not receive the 10% discount; (2) no extraction of CTA/SBC from current rates will be made; (3) CL&P will assume that C&LM and the Renewables Charge are in current rates; and (4) in the case of Rate 985, these limitations are not applicable to the general service tariffs referenced as the source of elements of these charges.

Under the Stipulation, CL&P would not create a new assessment for SBC, CTA, C&LM or the Renewables Charge. Tr. 8/17/99, pp. 1682-1683. Rather, the Company would assume that each of these charges is currently in rates. Id. According to CL&P, this treatment would be consistent with its proposed treatment of special contract customers. Tr. 8/17/99, p. 1686.

The Department approves the Stipulation submitted August 9, 1999, as filed. Absent this Stipulation, customers on Rates 21, 39, 985 and DRR would experience a rate increase effective January 1, 2000, because they have not been deemed to be special contracts and would therefore be assessed the CTA and SBC in addition to their current base rates. The Department believes that the Act did not intend for customers of any class to experience a rate increase effective January 1, 2000. Furthermore, the proposed treatment of revenues from these rate classes, imputing revenues to the unbundled functional components, will not decrease the level of SBC and CTA revenues projected by the Company. See June 9 Revision, Exhibit 12.

In its Application, the Company proposed to revise the general Rules and Regulations governing its tariff. Additionally, it proposed to institute Terms and

Conditions for Electric Suppliers. The Department will not consider these revisions in this proceeding, but will take them up in a reopening of Docket No. 98-01-02.

4. Energy Adjustment Clause

According to the Company, the Act contemplates an EAC that will continue to operate for the term of the standard offer to reflect market-based changes in the cost of energy procured for the Standard Offer. Furthermore, the Company argues that the EAC would also reflect changes in state and federal taxes, including the gross earnings tax. June 9, 1999 Revision, p. 39.

The Company states that an EAC is necessary during the Standard Offer period because mismatches between revenues and costs can occur due to: (1) variable pricing provisions with the supply portfolio; (2) mismatches in billing cycle versus supply charge periods; (3) inclusion of non-variable costs in the generation services retail prices; and (4) variance in rate design between the generation service supply and retail pricing. Response to Interrogatory EL-49. Generally, the Company cites Section 20(e) of the Act, which states that electric distribution companies shall be entitled to recover reasonable costs incurred as a result of providing SOS or back-up electric generation service. Response to Interrogatory EL-50.

The Company misinterprets Section 20 of the Act to allow for certain tax changes to be addressed in an EAC proceeding. Conn. Gen. Stat. § 16-19b was not amended by the Act. Any EAC approved by the Department under § 16-19b may recover the costs of energy that are proper for ratemaking purposes and for which the Department has not authorized recovery through base rates. Such costs now may include oil, gas, coal, nuclear fuel, wood or other fuels, and energy transactions with other utilities, nonutility generators or power pools, and the gross earnings tax imposed by § 12-264 on the revenues from the energy sources subject to the adjustment clause. This list of costs does not include changes in state and federal taxes or gross earnings taxes imposed on revenues not subject to the adjustment clause. The Department rejects the Company's proposal to use the EAC to adjust its revenue requirements to reflect changes in state and federal taxes.

The EAC was created to permit the Company to recover sufficient revenues to meet the costs for volatile energy costs. These costs were not only volatile, but represented a significant portion of the Company's overall costs as a fully integrated electric utility. On a practical level, the need for this adjustment mechanism is diminished since the Company no longer provides generation. The Company admits that if it receives non-variable priced bids to supply SOS, the EAC "would certainly be a lot less necessary." Tr. 8/9/99, p. 1087. Indeed, the Department believes that the EAC, which has a $9 million collar mechanism, is not the optimal method for conducting the Company's proposed adjustments for mismatches in billing cycles and variance in rate design between the generation service supply and retail pricing. The Department also notes that while the EAC is in effect, it will continue to be a line item on customer bills.

The Act states that the Standard Offer rate shall be adjusted pursuant to Conn. Gen. Stat. § 16-19b, and that the Company will be permitted to recover reasonable costs to provide SOS electric generation services. See Section 20. Furthermore,